A Comprehensive Approach for Reliability Worth Assessment of the Automated Fault Management Schemes

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***Abstract*-- Distribution automation application for fault management in the electricity distribution networks is one of the main potential remedial actions to reduce customers' outage times and hence improve service reliability. For this purpose, various automation schemes have been developed and introduced in different countries and by different venders. However, the challenge for electric utilities, especially in today's competitive electricity market, is to identify and evaluate potential reliability reinforcement schemes. Accordingly, appropriate schemes must be determined and prioritized for implementation. In this context, reliability cost/worth assessment plays an important role. A comprehensive approach is proposed in this paper to quantitatively assess the effects of various automated fault management schemes on the distribution system reliability.**

***Index Terms*—Distribution Automation, Automation Schemes, Fault Management, Reliability Assessment, Distribution System.**

I. Introduction

Analysis of customer failure statistics in the most electric utilities indicates that electric power distribution systems make the greatest individual contribution to the unavailability of supply to customers. Typical distribution system accounts for 25-40% of the cost to deliver power and 80-90% of customer reliability problems [1-3]. These statistics reinforce the need to be concerned with the reliability evaluation of distribution systems, to evaluate quantitatively the merits of various reinforcement schemes available to the planner and to ensure that the limited capital resources are used to achieve the greatest possible incremental reliability and improvement in the system.

Electric utilities can improve the distribution system reliability either through preventive measures or by appropriate remedial actions in response to a disturbance. Preventive measures include tree trimming on a regular basis, construction design modification, installation of lightning arresters and use of animal guards. Remedial action capabilities include those provided by protection schemes and various distribution automation functions [4-5]. Distribution automation application for fault management in the electricity distribution networks is one of the main potential remedial actions to reduce customers' outage times and hence improve service reliability. For this purpose, various automation schemes have been developed and introduced in different countries and by different venders [6-7].

A balance of appropriate preventive measures and/or remedial actions is the best way to improve distribution system reliability. Each electric utility is different from another one and has its own set of worst causes for distribution outages. In addition, the design history and distribution circuit configuration will have a large impact on the specific solutions to be selected [8]. Therefore, the challenge for electric utilities, especially in today's competitive electricity market, is to identify and evaluate potential reliability reinforcement schemes and then determine and prioritize those appropriate for implementation. In this context, reliability cost/worth assessment plays an important role [1-2]. Reliability cost refers to the investment needed to achieve a certain level of adequacy. Reliability worth is the benefit derived by the utility, consumer and society because of higher reliability due to more investment in the system. Although estimating the reliability cost is straightforward, but direct measurement of reliability worth due to system reinforcement is difficult. One surrogate way to measure the reliability worth is to evaluate customer interruption cost. The reliability cost/worth concept can be illustrated using Figure 1.

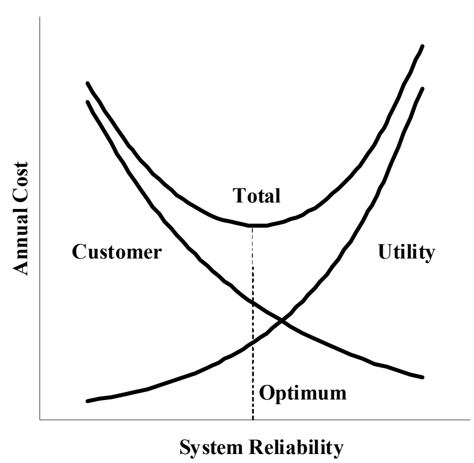

Fig. 1. Costs as a function of system reliability

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Figure 1 shows that the utility cost will generally increase with higher investment cost in equipment and facilities which provide higher reliability. On the other hand, the customer interruption costs due to higher reliability will decrease. The total cost to society is the sum of these two costs. There is a minimum point in the resulting total cost curve which indicates the optimal target level of reliability. Reliability cost/worth analysis is used to find this optimal point.

A comprehensive approach is proposed in this paper to quantitatively assess the effects of various automated fault management schemes on the distribution system reliability. The proposed technique is based on the event tree method and the concepts of conditional probability approach. The general concepts behind this proposed technique have been already published in a few research works including those developed by the authors [9-14]. However, the reliability evaluation procedure in this paper has been modified and generalized to be applicable for reliability assessment of the distribution systems in presence of any kind of automated fault management schemes.

II. Fault Management Activities

When a distribution network encountered with a specific failure mode of its components, the whole or some of the following fault management activities are carried out:

1) Protection System Reaction Process: The associated protection system will detect the abnormal situation and will operate to interrupt this abnormal condition according to its operational logic. In what manner this process is carried out depends on several factors such as the type of fault, setting and operational logic of protection system, and design and operation policies of distribution network. The time required to accomplish this process is very short. However, the outcome of this process has a vital impact on the extent of affected customers and the interruption type (sustained or momentary) that they may be encountered.

2) Fault Notification Process: The system operators will be notified about a sustained power interruption somewhere in the distribution system.

3) Approximate Fault Location Process: The related fault information and system configuration are collected and analyzed to find the fault location and the extent of customers that affected by the fault.

4) Decision Making Process: The fault isolation and service restoration procedure are determined based on the factors such as approximate location of the fault, type of affected customers, number, location and type of switching devices involved and also available repair crew for fault isolation and service restoration activities.

5) Repair Crew Dispatching and Traveling Process: Once the approximate location of outages is known, repair crew is dispatched around the damaged area. The location, date and time of fault occurrence affects the travel time of repair crew to get around the damaged area.

6) Patrolling Process: After repair crew receives to the damaged area, they drive along the feeder to look for the damaged component. The time required to accomplish this process is dependent on the factors such as daylight, accessibility to the suspected feeder and its components, available resources and facilities and so on.

7) Fault Isolation Process: After the damaged component is located, it has to be isolated from the rest of the system. This is usually done by manually and/or remotely operating the switching devices. Coordination between the repair crew and dispatchers is maintained via portable radio to perform this task properly. The fault isolation process may involve various switching actions. The duration of this process depends on the number, type and location of switching devices involved, available resources to open or close these switching devices and the switching sequences such as parallel, sequential and combination of both [15].

8) Service Restoration Process: The next step is to restore power to those parts of the system which are undamaged but have lost power because of problems elsewhere in the system. The power to these parts may be provided from alternate routes. The dispatchers determine such possible routes and may ask the repair crew to operate some other switching devices. The duration of this process is also depends on some factors such as those outlined for fault isolation process.

9) Repair or Replacement Process: The damaged component should be repaired or replaced in order to return the network configuration to the normal operating condition and to restore power to customers that can only be restored after repair or replacement of the damaged component. The duration of this process depends on factors such as the policies of distribution utility, type of the interrupted customers, regulatory environment, type of the damaged component, and available resources and facilities to accomplish it in parallel or after service restoration activities.

10) Return to Normal Operation Process: Usually fault isolation and service restoration activities necessitate changing the normal configuration of distribution network. As the normal configuration of system is the basis for day-to-day operating and also setting of protection relays, it is necessary to return the distribution network to its normal operating configuration. This process is accomplished after repair or replacement of the damaged component. It usually needs to special switching sequences which may cause other interruptions for some group of customers. The duration of this process and its affects on the customers depends on factors such as type, location and number of available switching devices, type and location of customers that may be affected, policies of distribution utility and available resources to open or close these switching devices and the switching sequences such as parallel, sequential and the combination of both.

In a distribution network without any automation, since all of the above processes are performed manually, it may take a long time to restore power to those parts of distribution system which are undamaged but have lost power because of problems elsewhere in the distribution network (say 50 to 80 minutes) and also to restore power to customers that can only be restored after repair or replacement of the damaged component (say 1 to 5 hours). However, when an automated fault management scheme is applied to the distribution network, depending on the operational procedure of the implemented automation scheme, all or some parts of fault management activities can be accomplished automatically. Hence, some or whole of the above processes can be completed more efficiently by less people in much less time, which increase distribution system reliability and efficiency.

III. Evaluation Procedure

A. General Concepts

A modular approach should be used to evaluate the impacts of various automated fault management schemes on distribution system reliability. Successful operation of the implemented automation scheme, during various stages of fault management activities, has vital effect on the expected results. The automation scheme may comprise one or more automation functions. These automation functions are designed to assist in the specific stage of fault management activities. Each automation function relies on successful operation of some components of the implemented automation scheme. For example, remote switching function, which should operate during fault isolation and service restoration stages, depends on successful operation of remote controlled switching devices, communication systems and control centre facilities. Therefore, different failure modes of these components should be considered in the operational logic of automation scheme for performing its intended functions. In the proposed approach, the automation scheme is divided into modules that can be analyzed independently. The reliability data associated with each module can be either derived by a separate reliability analysis or obtained from a data collection method. Each module may contain processing units, switchgear, power supply units, timers, relays, sensors, communication systems and so on. These modules have no shared components and are considered to be independent. They are usually responsible for one or more specific tasks (protection, communication, control and monitoring) in the overall automation scheme. Then, the procedure of implemented automation scheme, when a specific fault (phase or ground, transient or permanent) occurs on a component of distribution network, is identified for various stages of fault management activities. This procedure usually involves the sequential operation logic of a set of its modules. Therefore, the consequence of the availability and unavailability of each involved modules is analyzed using the event tree method. Finally, based on the concepts of conditional probability approach, the interruption frequency and restoration time of the load points are calculated using the outcomes of event trees and their corresponding probabilities. System oriented reliability indices are then determined by aggregating the load point indices.

B. Steps of Evaluation Procedure

A comprehensive study has been performed to develop appropriate formulas, models and evaluation procedure for determining the impacts of automated fault management schemes on distribution system reliability. They can be summarized in the following steps:

(1) Based on the above described general concepts, the intended automation scheme is divided into some suitable modules that can be analyzed independently. Then, an appropriate reliability model should be deduced for each module of this automation scheme from operational failure point of view. It should be noted that, probability of operational failure is the conditional probability that a device will not operate if it is required to operate. The reliability data associated with each module can be either derived by a separate reliability analysis or obtained from a data collection method. The number of modules involved in the analysis and the characteristic of their reliability models can have any degree of complexity, depending on the operating logic of implemented automation scheme, type of desired analysis and available data.

(2) The affected customers and operational procedure of implemented automation scheme for various stages of fault management activities, when a specific fault (phase or ground, transient or permanent) occurs on a component of distribution network, are identified. Then, using the deduced modules and their reliability models, the event tree is developed. The sequences of events together with the associated outcomes in the operating procedure of automation scheme are then identified. After that, for the affected customers, the interruption durations, the number of momentary interruptions before supply reestablishment and the associated probabilities are determined.

(3) Three classes of interruptions, designated as Sustained Interruption, Momentary Interruption and Momentary Interruption Event are considered in the analyses [15]. Based on the results obtained from Step 2, the contribution to the sustained, momentary and momentary interruption event frequency of L_j which has been affected by a specific fault on C_i are determined using the concept of expectations:

$$\lambda^{S}_{C_i^f L_j} = \sum_{e=1}^{NEC_i^f}\Big(\{(\lambda_{C_i^f} | ET^{e}_{C_i^f L_j}) \times P(ET^{e}_{C_i^f L_j})\} \times IDT^{e}_{C_i^f L_j}\Big) \quad (1)$$

$$\lambda^{M}_{C_i^f L_j} = \sum_{e=1}^{NEC_i^f}\Big(\{((\lambda_{C_i^f} \times NMI^{e}_{C_i^f L_j}) | ET^{e}_{C_i^f L_j}) \times P(ET^{e}_{C_i^f L_j})\} \times (1 - IDT^{e}_{C_i^f L_j})\Big) \quad (2)$$

$$\lambda^{ME}_{C_i^f L_j} = \sum_{e=1}^{NEC_i^f}\Big(\{(\lambda_{C_i^f} | ET^{e}_{C_i^f L_j}) \times P(ET^{e}_{C_i^f L_j})\} \times (1 - IDT^{e}_{C_i^f L_j})\Big) \quad (3)$$

$$IDT^{e}_{C_i^f L_j} = \begin{cases} 1 & TID^{e}_{C_i^f L_j} \geq MIT \\ 0 & TID^{e}_{C_i^f L_j} < MIT \end{cases} \quad (4)$$

Where:

C_i	Component number i
C_i^f	Component number i which encounters with mode f of fault
L_j	Load point number j which has been affected by a specific fault on C_i

$\lambda^{S}_{C_i^f L_j}$ Contribution to the sustained interruption frequency of L_j due to mode f of fault on C_i

$\lambda^{M}_{C_i^f L_j}$ Contribution to the momentary interruption frequency of L_j due to mode f of fault on C_i

$\lambda^{ME}_{C_i^f L_j}$ Contribution to the momentary interruption event frequency of L_j due to mode f of fault on C_i

$\lambda^{f}_{C_i}$ Rate of mode f of fault on C_i

NEC_i^f Number of event tree outcomes deduced for mode f of fault on C_i

$ET^{e}_{C_i^f L_j}$ Situation in which outcome number e of the deduced event tree indicates that L_j is affected by mode f of fault on C_i

$P(ET^{e}_{C_i^f L_j})$ Probability associated with $ET^{e}_{C_i^f L_j}$

$NMI^{e}_{C_i^f L_j}$ Number of momentary interruptions imposed to L_j by mode f of fault on C_i and corresponding to outcome number e of deduced event tree

$TID^{e}_{C_i^f L_j}$ Total interruption duration imposed to L_j by mode f of fault on C_i and corresponding to outcome number e of the deduced event tree

MIT Momentary interruption threshold which an interruption longer than that is considered as a sustained interruption

(4) The contribution to the sustained annual outage time of L_j which has been affected by a specific fault on C_i is determined based on the concept of expectations and using the results obtained in Step 2:

$$U^{S}_{C_i^f L_j} = \lambda_{C_i^f} \times \sum_{e=1}^{NEC_i^f} \left(\{(TID^{e}_{C_i^f L_j} | ET^{e}_{C_i^f L_j}) \times P(ET^{e}_{C_i^f L_j})\} \times IDT^{e}_{C_i^f L_j} \right) \quad (5)$$

Where:

$U^{S}_{C_i^f L_j}$ Contribution to the sustained annual outage time of the affected L_j due to mode f of fault on C_i

(5) The contribution to the expected interruption cost of L_j which has been affected by a specific fault on C_i is also determined based on the concepts of conditional probability theory and using the results obtained in Step 2:

$$ECOST_{C_i^f L_j} = La_{L_j} \times \lambda_{C_i^f} \times \sum_{e=1}^{NEC_i^f} \left((CIC_{L_j}(TID^{e}_{C_i^f L_j}) | ET^{e}_{C_i^f L_j}) \times P(ET^{e}_{C_i^f L_j}) \right) \quad (6)$$

Where:

$ECOST_{C_i^f L_j}$ Contribution to expected interruption cost of the affected L_j due to mode f of fault on C_i

La_{L_j} Average load connected to L_j

$CIC_{L_j}(t)$ Per unit customer interruption cost of L_j due to an interruption with duration of t in ($/kW)

(6) The load-point and system oriented reliability indices are determined by analyzing the contributions associated with all components of distribution network and their various failure modes. The load-point reliability indices are calculated as follows:

$$\lambda^{S}_{L_j} = \sum_{i=1}^{NC} \sum_{f=1}^{NFC_i} \lambda^{S}_{C_i^f L_j} \quad (7)$$

$$\lambda^{M}_{L_j} = \sum_{i=1}^{NC} \sum_{f=1}^{NFC_i} \lambda^{M}_{C_i^f L_j} \quad (8)$$

$$\lambda^{ME}_{L_j} = \sum_{i=1}^{NC} \sum_{f=1}^{NFC_i} \lambda^{ME}_{C_i^f L_j} \quad (9)$$

$$U^{S}_{L_j} = \sum_{i=1}^{NC} \sum_{f=1}^{NFC_i} U^{S}_{C_i^f L_j} \quad (10)$$

$$r^{S}_{L_j} = \frac{U^{S}_{L_j}}{\lambda^{S}_{L_j}} \quad (11)$$

$$EENS^{S}_{L_j} = U^{S}_{L_j} \times La_{L_j} \quad (12)$$

$$ECOST_{L_j} = \sum_{i=1}^{NC} \sum_{f=1}^{NFC_i} ECOST_{C_i^f L_j} \quad (13)$$

$$IEAR_{L_j} = \frac{ECOST_{L_j}}{EENS_{L_j}} \quad (14)$$

Where:

$\lambda^{S}_{L_j}$ Average sustained interruption frequency of L_j

$\lambda^{M}_{L_j}$ Average momentary interruption frequency of L_j

$\lambda^{ME}_{L_j}$ Average momentary interruption event frequency of L_j

$U^{S}_{L_j}$ Average sustained annual outage time of L_j

$r^{S}_{L_j}$ Average sustained outage time of L_j

$EENS^{S}_{L_j}$ Average expected energy not supplied of L_j

$ECOST_{L_j}$ Average expected interruption cost of L_j

$IEAR_{L_j}$ Average interrupted energy assessment rate of L_j

NC Number of distribution network components

NFC_i Total number of various failure modes of C_i

The following system oriented reliability indices can also be calculated using the load point indices:

$$\mathrm{SAIFI} = \frac{\sum_{j=1}^{NLP} (\lambda_{L_j}^{S} \times N_{L_j})}{\sum_{j=1}^{NLP} N_{L_j}} \tag{15}$$

$$\mathrm{MAIFI} = \frac{\sum_{j=1}^{NLP} (\lambda_{L_j}^{M} \times N_{L_j})}{\sum_{j=1}^{NLP} N_{L_j}} \tag{16}$$

$$\mathrm{MAIFI_E} = \frac{\sum_{j=1}^{NLP} (\lambda_{L_j}^{ME} \times N_{L_j})}{\sum_{j=1}^{NLP} N_{L_j}} \tag{17}$$

$$\mathrm{SAIDI} = \frac{\sum_{j=1}^{NLP} (U_{L_j}^{S} \times N_{L_j})}{\sum_{j=1}^{NLP} N_{L_j}} \tag{18}$$

$$\mathrm{ASAI} = \frac{\sum_{j=1}^{NLP} (8760 \times N_{L_j}) - \sum_{j=1}^{NLP} (U_{L_j}^{S} \times N_{L_j})}{\sum_{j=1}^{NLP} (N_{L_j} \times 8760)} \tag{19}$$

$$\mathrm{EENS} = \sum_{j=1}^{NLP} (U_{L_j}^{S} \times La_{L_j}) = \sum_{j=1}^{NLP} \mathrm{EENS}_{L_j}^{S} \tag{20}$$

$$\mathrm{ECOST} = \sum_{j=1}^{NLP} \mathrm{ECOST}_{L_j} \tag{21}$$

$$\mathrm{IEAR} = \frac{\mathrm{ECOST}}{\mathrm{EENS}} \tag{22}$$

Where:

N_{L_j}	Number of customers of L_j
NLP	Number of Load Points
SAIFI	System Average Interruption Frequency Index
MAIFI	Momentary Average Interruption Frequency Index
$\mathrm{MAIFI_E}$	Momentary Average Interruption Event Frequency Index
SAIDI	System Average Interruption Duration Index
ASAI	Average System Availability Index
EENS	Expected Energy Not Served
ECOST	Expected Interruption Cost
IEAR	Interrupted Energy Assessment Rate

IV. Illustrative Example

To be familiar with the steps of the proposed evaluation procedure, application of the proposed technique is illustrated using an ordinary feeder shown in Fig. 2. This feeder is an overhead line with a circuit breaker in the beginning of feeder and three load break switches along it. It is assumed that feeder circuit breaker and switches SW1 and SW3 can be operated remotely by distribution system operators located in the control center. It is also assumed that SW2 is a manually operated switch. The automated scheme for fault management on this feeder is designed to work as follows.

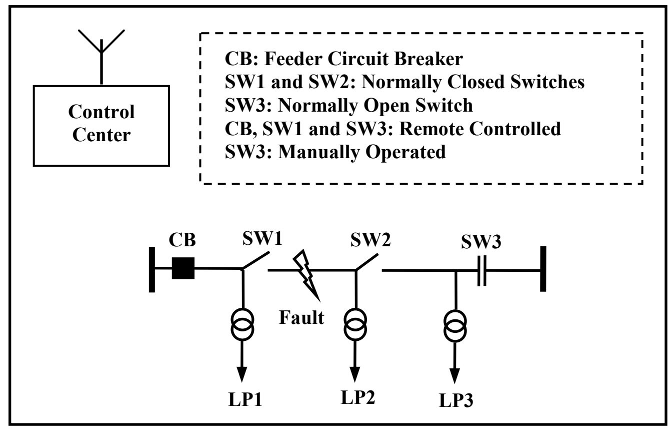

Fig. 2. An ordinary overhead line feeder equipped with an automat scheme for fault management activities.

Consider a typical permanent phase fault on a line section between SW1 and SW2, as shown in Fig. 2. The feeder circuit breaker trips and locks out after its predefined reclosing sequences. After that, circuit breaker reports its status to control center. Then, the fault location facilities, located in the control center, automatically gather fault information from fault indicators located beside remote controlled switching devices, i.e. CB, SW1 and SW3. By analyzing the collected information, it is found that the fault is between SW1 and SW2. Afterwards, an application software, which is responsible for fault isolation and service restoration activities, provides a suitable procedure for isolation of the fault and restoring power supply to the healthy parts of the feeder. It also assists repair crew during fault location process. For example, for this typical fault, it recommends the operator to open SW1 and to close CB remotely. By accomplishing this task, power supply will be restored for customers on the section between CB1 and SW1. After that, it guides the repair crew to get around probable area of fault as soon as possible. Repair crew will open the manually operated SW2 and ask system operator to close the normally open SW3. As a result of this task, power supply will also be restored for customers on sections between SW2 and SW3. Then repair crew start patrolling around possible location of the fault. After finding the damaged component, the repair or replacement process will be started. By accomplishing this task, repair crew asks system operator to close SW1. This will result in power supply returning for interrupted customers on the section between SW1 and SW2. Finally, repair crew goes to the location of manually operated SW2, close it and after a few seconds ask system operator to open SW3. As a result of this activity, the feeder returns to its normal operating configuration and all the fault management activities accomplish for this supposed fault.

The evaluation procedure for reliability worth assessment of the simple automated feeder shown in Fig. 2 can be summarized in the following steps:

(1) The automation scheme is divided into 4 modules, corresponding to those components which have vital impacts on the procedure of automation scheme for fault management activities. They are control centre facilities, CB, SW1 and SW3. These modules have no shared components and are considered to be independent. Then, an appropriate reliability model should be deduced for each one of these modules from operational failure point of view. As already mentioned, these reliability models can have any degree of complexity, depending on the operating logic of implemented automation scheme, type of desired analysis and available data. Suppose that the impact of operational failure of communication devices of these modules is also desired in the reliability worth assessment of the implemented automation scheme. Then, each model can be represented by a two states reliability model, as shown in Fig. 3. The UP state is corresponding to situation that the communication devices of the intended module are required to do and they work successfully. Contrary, the DN state represents the situation where these devices fail to operate successfully when they are required to do. The reliability data associated with each model can be either derived by a separate reliability analysis of the intended modules or obtained from a data collection method.

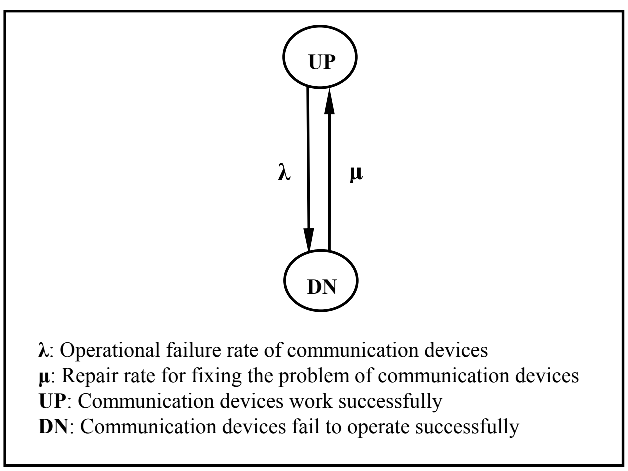

Fig. 3. A two state reliability model for representing operational failure of communication devices of the intended modules

(2) The affected customers and the operational procedure of the implemented automation scheme for various stages of fault management activities, when a specific fault occurs on a component of distribution network is identified. This procedure for a typical permanent phase fault on a line section between SW1 and SW2 was already described. Then, using the deduced modules and their reliability models, an event tree is developed for this specific fault, as shown in Fig. 4. The sequences of events together with the associated outcomes in the operating procedure of this automation scheme are then identified. Then, for the affected customers (load points LP1, LP2 and LP3), the interruption durations, the number of momentary interruptions before supply reestablishment and the associated probabilities are determined similar to the following examples. When deducing these parameters, it is assumed that there is just one available repair team for dealing with this fault; therefore, field activities have to be done sequentially. It is also supposed that the main substation is unmanned, therefore, in the case of fail to close CB remotely, it is necessary to visit substation and close it manually.

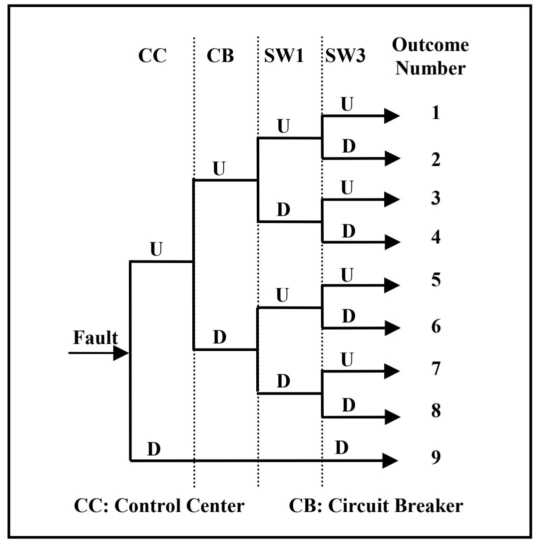

Fig. 4. An event tree that has been deduced for a typical fault shown in Fig. 2

- Event Number 1:

$$TID^1_{C_i^f L_1} = (T_{PSR} + T^A_{FN} + T^A_{FL} + T^A_{DM}) + (T^R_{FI} + T^R_{SR})$$

$$NMI^1_{C_i^f L_1} = CB_{TROL}$$

$$P(ET^1_{C_i^f L_1}) = CC^{UP} \times CB^{UP} \times SW1^{UP} \times SW3^{UP}$$

$$TID^1_{C_i^f L_3} = TID^1_{C_i^f L_1} + (T^A_{RCDT} + T^M_{FI} + T^R_{SR})$$

$$NMI^1_{C_i^f L_3} = CB_{TROL}$$

$$P(ET^1_{C_i^f L_3}) = P(ET^1_{C_i^f L_1})$$

$$TID^1_{C_i^f L_2} = TID^1_{C_i^f L_3} + (T^A_P + T_R + T^R_{SR})$$

$$NMI^1_{C_i^f L_2} = CB_{TROL}$$

$$P(ET^1_{C_i^f L2}) = P(ET^1_{C_i^f L_1})$$

- Event Number 4:

$$TID^4_{C_i^f L_1} = (T_{PSR} + T^A_{FN} + T^{SA}_{FL} + T^A_{DM}) + (T^A_{RCDT} + T^M_{FI} + T^R_{SR})$$

$$NMI^4_{C_i^f L_1} = CB_{TROL}$$

$$P(ET^4_{C_i^f L_1}) = CC^{UP} \times CB^{UP} \times SW1^{DN} \times SW3^{DN}$$

$$TID^4_{C_i^f L_3} = TID^4_{C_i^f L_1} + (T_{FI}^M + T_{SR}^M)$$
$$NMI^4_{C_i^f L_3} = CB_{TROL}$$
$$P(ET^4_{C_i^f L_3}) = P(ET^4_{C_i^f L_1})$$

$$TID^4_{C_i^f L_2} = TID^4_{C_i^f L_3} + (T_P^{SA} + T_R + T_{SR}^M)$$
$$NMI^4_{C_i^f L_2} = CB_{TROL}$$
$$P(ET^4_{C_i^f L2}) = P(ET^4_{C_i^f L_1})$$

- Event Number 9:

$$TID^9_{C_i^f L_1} = (T_{PSR} + T_{FN}^{SA} + T_{FL}^{SA} + T_{DM}^{SA}) + (T_{RCDT}^{A} + T_{FI}^M + T_{SR}^M)$$
$$NMI^9_{C_i^f L_1} = CB_{TROL}$$
$$P(ET^9_{C_i^f L_1}) = CC^{DN}$$

$$TID^9_{C_i^f L_3} = TID^9_{C_i^f L_1} + (T_{FI}^M + T_{SR}^M)$$
$$NMI^9_{C_i^f L_3} = CB_{TROL}$$
$$P(ET^9_{C_i^f L_3}) = P(ET^9_{C_i^f L_1})$$

$$TID^9_{C_i^f L_2} = TID^9_{C_i^f L_3} + (T_P^{SA} + T_R + T_{SR}^M)$$
$$NMI^9_{C_i^f L_2} = CB_{TROL}$$
$$P(ET^9_{C_i^f L2}) = P(ET^9_{C_i^f L_1})$$

Where:

T_{PSR} Average time required for detection of the abnormal situation by the associated protection system and operation to interrupt this abnormal condition according to its operational logic

T_{FN} Average time required for control center operators to be notified about a sustained power interruption somewhere in the distribution system

T_{FL} Average time required for control center operators to find an approximate location of the fault

T_{DM} Average time required for control center operators to make decision about fault management activities

T_{RCDT} Average time required to dispatch and travel of repair crew around the damaged area

T_P Average time required for repair crew to patrol along the feeder to look for the damaged component

T_{FI} Average time required to isolate the fault from the rest of system

T_{SR} Average time required to restore power to healthy parts of the system

T_R Average time required to repair or replacement of the damaged component

CB_{TROL} Total number of reclosing operations of feeder circuit breaker to lockout

Superscribes A and SA are used when a process is aided by some facilities as automatically or semi-automatically, respectively. Superscribes R and M are used when a process involving switching device operation is accomplished remotely by control centre operators or manually by repair crew in the location of switching device, respectively.

(3)-(5) Based on the results obtained from Step 2, the contribution to the sustained, momentary and momentary interruption event frequency, sustained annual outage time and expected interruption cost of load points LP1, LP2 and LP3 which have been affected by this typical fault are determined using the equations 1-6.

(6) Steps 2 to 5 are repeated for all possible failure modes of this failed component. After that, the next component is selected and whole of this process are repeated until those contributions of all components of distribution network and their various failure modes are considered into analyses. Finally, the load-point and system oriented reliability indices are determined using the equations 7-22.

The reader is invited to refer [9-14] for quantitatively application of the proposed technique to a distribution reliability test system in presence of some kinds of automated fault management schemes.

V. Conclusion

Electric utilities can improve distribution system reliability through various methods. A balance of these methods is the best way to improve distribution system reliability. Each electric utility is different from another one and has its own set of worst causes for distribution outages. In addition, the design history and distribution circuit configuration will have a large impact on the specific solutions to be selected. Therefore, electric utilities should identify and evaluate potential reliability reinforcement solutions and then determine and prioritize those appropriate for implementation.

Distribution automation application for fault management in the electricity distribution networks is one of the main potential remedial actions to reduce customers' outage times and hence improve service reliability. For this purpose, various automation schemes have been developed and introduced in different countries and by different venders.

This paper proposed a comprehensive approach to quantitatively assess the effects of various automated fault management schemes on the distribution system reliability. The proposed technique is based on the event tree method and the concepts of conditional probability approach. This evaluation procedure is summarized in some steps. In order to be familiar with the steps of the proposed evaluation procedure, application of the proposed technique is illustrated using an illustrative example.

VI. ACKNOWLEDGMENT

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